Staff Testimony on:
INCENTIVES FOR NEW MARKET ENTRANTS AND THE ROLE OF DEMAND BIDDING

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INTRODUCTION

In this paper we examine incentives to entering the electric generation market under the new competitive market structure proposed by the California Public Utilities Commission (CPUC). At the same time we evaluate prospects for existing generators in the market to recover their fixed costs, because the issues involved are nearly the same. Whether for a new generator or an existing one, the fundamental question is whether the new market offers a fair chance to timely recover the full variable and fixed costs of generation, including any necessary return on invested capital.

Taking the point of view of the electricity consumer rather than the generator, we also examine whether a pricing structure such as might evolve in the restructured market would be conducive to economic efficiency. Economic efficiency is defined in the Energy Commission's ***ER 94*** as, "a measure of the total value to society of a good or service; it takes into account both the worth to society and the price it pays." [1]

With its Decision of Dec. 20, 1995, a majority of the CPUC set the state on a course toward profound change in the way its electric utility industry is structured and operated. [2] In the new formulation, market forces will determine how much electrical energy can and will be generated. Government regulation will play a lesser role.

The proposed restructuring is not so radical as to raise any serious prospect of major system failures. However, it would bring about significant changes to a system that has functioned at least *reasonably* well for a long time. The implications of these changes should be examined beforehand to the extent possible. We suggest and discuss implications.

THE POWER EXCHANGE AND DIRECT ACCESS

The Decision orders the utilities to open the business of generation to competition by way of a Power Exchange (PX), and bilateral contracts facilitated by open access to transmission. The PX (a wholesale power pool) will be an open market for electrical energy as a commodity. Any generator will be able to offer energy for sale in this market, and the existing investor-owned utilities will be required, during a transition period, to both sell all the energy they produce into the PX and buy all the energy they sell to their full service customers from the PX. At the same time, open access to utility transmission will allow non-utility generators and their customers to enter into private energy contracts outside the PX (direct access) or "contracts for differences," wherein both parties deal through the PX but settle pricing between themselves (virtual direct access).

The PX will match demand for electricity with supply by means of an auction that sets prices for each hour. Generators will submit bids for quantities they will supply at stated prices. Users of electric power, or aggregators representing them, will submit demand bids for quantities they are willing to purchase. Supply will be matched to demand at a market clearing price (MCP) paid to all generators. MCPs will be determined by location, so they will be different if congestion on transmission lines inhibits the free movement and dispersion of power. However, for purposes of this paper, congestion effects will be ignored, except in a separate section on "Locational Pricing".

The CPUC Decision is not clear as to whether demand bids should include prices. The decision, however, may no longer contain the most authoritative description of the PX. As ordered in the decision, the utilities filed a joint applications to the Federal Energy Regulatory Commission (FERC) on April 29, 1996. Separate applications seek authorization of an Independent System Operator (ISO) and the PX. The latter application was filed pursuant to Section 205 of the Federal Power Act, and is therefore known as "the 205 filing". It assumes that at least some of the demand bids will state both quantities and corresponding prices.

According to the 205 filing, generator bids will have three components: 1) incremental energy ($/MWh), 2) no-load ($/hr.), 3) start-up ($). If the filing complies with the decision that ordered it, the latter two components reflect payments that would be made only to the extent necessary; i.e., "not covered through the MCPs for energy." (p. 49, 12/20/95 decision)

Demand bids, according to the 205 filing, include both load and associated price information: "A buyer submitting a demand bid may state, for each hour, a different price preference for each demand quantity in each location, i.e., the maximum price in each hour at which it is prepared to take a specified amount of energy in the day-ahead schedule. If demand is bid without a price, it is assumed that the bidder is prepared to pay the market-clearing price". (page 44 of the 205 filing)

In matching supply to demand, the PX will order bids from generators according to their cost, such that the least expensive are taken (dispatched) first. Likewise, demand bids will be placed in price order, with those expressing the highest willingness to pay taken (satisfied) first. The process of matching is complete when either all demand is met or the next increment of demand is not willing to pay the price bid by the corresponding increment of supply. The MCP is then determined by the higher of: a) the last and highest priced generator bid dispatched; or, b) the last and highest priced demand bid satisfied. This is an interpretation of the 205 filing. The exact words from the filing (page 49) are as follows:

- If supply is sufficient to meet demand at or below the demand price bid, the market-clearing price will be set by the marginal generating unit.

- If demand at a price exceeds supply, the market-clearing price will be set by the lowest winning demand price bid. In the absence of adequate demand price bids, demand will be curtailed to match supply, and the market-clearing price will be set equal to an administratively pre-determined cap.

Operation of these principles is demonstrated in the following examples in which the numbers represent price bids in $/MWh and all bids, supply (S) or demand (D), are for the same quantity at the same location. MCPs are shown in bold.

Case A		**Case B**		**Case C**	
S	D	S	D	S	D
16	99	16	99	16	99
24	56	24	56	24	85
35	40	35	**40**	35	80
50	28	50	38	50	**75**
					70

In Case A, supply at $35/MWh meets all demand that bid a higher price, and the only un-dispatched supply bid is higher than the only unsatisfied demand bid. Thus the market clears at the bid of the marginal generating unit, or $35/MWh. In Case B, demand for power at $35/MWh exceeds supply at that price, so the $38/MWh demand bid will not be satisfied. The lowest "winning" demand bid is $40/MWh, which sets the MCP. In Case C, all demand bids exceed the highest supply bid, but demand quantity exceeds supply quantity. The $70/MWh demand bid will not be satisfied, and MCP will be the bid of the highest "winning" demand bid, or $75/MWh.

No example is given of the case in which demand price bids are not "adequate", demand is "curtailed to match supply", and MCP is "set equal to an administratively pre-determined cap". The filing does not describe how the question of adequacy would be determined, how demand would be curtailed (particularly <u>whose</u> demand), or how high the cap price would be set. Apparently, the intent is that MCP should be high in this oversubscribed condition and that some of the demand might drop in response to the high price. Perhaps details will be filled in later.

The CPUC decision and subsequent filings to the FERC are as much about direct access as they are about the PX, but direct access, both "physical" and "virtual" is given little attention in this paper. In direct access, a seller contracts to sell power and a buyer contracts to buy it. Pricing is mutually agreed. Hypothetically, buyers could agree to pricing that would be sufficient to support new entrants into the generation market, but why would they? They would if they had to, and they would not have to so long as the PX could supply cheaper power. Therefore, PX prices are assumed in this paper to be the measure of whether new market entrants can survive. Some have argued that buyers seeking to avoid the volatility of the PX will pay prices sufficient to support new capacity. Volatility is, however, in the typical case, at least as much of a worry for the generator as for the buyer. In negotiations, it will likely work more in the buyer's favor. Thus, a generator that cannot meet its revenue requirements from selling into the PX is unlikely to do so by way of contract.

RELEVANT QUOTES FROM THE RESTRUCTURING DECISION

Under the heading, "The Power Exchange Provides a Visible Market for Generation," the 12/20/95 CPUC Decision says, "Over time the ability to observe the price information will send the most reliable signals with respect to the need for additional generation as well as cost-cutting steps required to keep existing units competitive." (p. 47)

Under "Responsibilities of the Power Exchange" (p. 48), the Decision says, "The Power Exchange will conduct an auction in which generators will submit bids under transparent bidding procedures. These bids should state the minimum price for which suppliers are willing to dispatch a specified amount of power the next day in hourly or half-hourly increments. The Power Exchange will then match the generators' bids with demand bids submitted by utilities, brokers, marketers or any authorized entity on behalf of end-use customers. (p. 49) A few sentences later, it goes on to say, "Every winning generation bidder will be paid the MCP at its location, which bid is consistent with both the bid and the supply and demand equilibrium." (p. 50)

A footnote a few pages later says, "Over time, as transition (sic) costs are eliminated and excess capacity diminishes, the clearing price for the electricity commodity will gradually reflect a value for capacity." (p. 55)

The function of MCPs in signalling opportunities to invest in new capacity is explained on the next page: "As an example, let us suppose a potential market entrant with access to a gas supply and computations which project the cost of generation with a state of the art combined cycle turbine at three cents. Knowledge that the Exchange is clearing eighty percent of the time at three and one half cents and above is precisely the type of information needed to develop a business plan to enter the market and obtain financial backing for such a step. This information is equally vital to a utility or non-utility owner of existing units with respect to the feasibility of a repower." (p. 56)

The Decision apparently envisions the Power Exchange and its MCPs as providing income streams sufficient to support the generators needed to meet system load, or at least the more efficient of such generators, and to encourage new ones to enter the market as needed. This would imply that Exchange prices should be high enough, on average, that they can cover the full costs of efficient generators including whatever return may be required on invested capital. Will actual Exchange prices be this high? If so, how and why?

MARGINAL COST PRINCIPLES

The Decision says nothing about how generators would determine their bids into the Exchange, but the Commission clearly intends to create a fully competitive market in which no participants make effective use of market power. Market power is defined in the decision as, "the ability of a particular seller or group of sellers to maintain prices profitably above competitive levels for a significant period of time." (p. 90) In such a market, generators should be expected to submit bids reflecting their short-run operating costs. The rationale for this is explained in the California Energy Commission's "Reply Comments on CPUC Proposed Structure for a Competitive Electricity Industry," dated August 22, 1995 (p. 10):

> If, . . . bidders know they will be paid the market-clearing price, they have no reason to search for it, no reason to guess at it; they can simply bid their variable operating costs. They do not have to, but they will tend to do so, because the incentive is there. By bidding only these costs, they know that they will be called upon to operate only if

> the market price they are paid at least covers their operating costs; if it doesn't cover those costs, they won't be dispatched and therefore won't incur those costs of suffer any operating losses. Hence, a system that pays bidders the market-clearing price encourages bidders to bid their variable operating costs, which in turn allows the ISO to conduct an economic dispatch/balancing service in merit order, at more-or-less the least total cost to system users.

This strategy assumes that an individual generator or generating company would ordinarily expect to be a price taker, rather than a price setter. A bidder who intends to receive exactly the price he bids is not likely to bid operating cost, because such a bid could bring no profit. A bidder who knows he will receive MCP, on the other hand, has an incentive to bid the marginal cost of generation. This is the same as variable cost in some cases, and in others not, as discussed and illustrated in **Attachment A**.[3]

To summarize the argument in **Attachment A**, generators bid as low as they can because this maximizes their chances of being dispatched and operating at any time when the MCP is high enough to return any contribution, small or large, to fixed cost recovery and profit. "As low as they can" is variable operating cost (fuel cost plus variable operation and maintenance cost) in the simplest case, where a generator has only one operating level. It is marginal costs for a unit with multiple operating levels. Marginal cost represents the change in hourly operating cost divided by change in output. This turns out to be equal or close to variable operating cost when the unit is operating in its most efficient range. Bidding higher than marginal or variable cost only causes a loss of potential net revenue during the hours when MCP is higher than either of these costs but lower than the price bid.

Attachment A does not entirely comport with the decision and the subsequent FERC filings in regard to recovery of no-load and start-up costs. No-load costs are associated with running a generating unit at sub-optimal levels of output. Start-up costs are incurred in bringing a unit on line from a condition of cold standby. In **Attachment A**, the generator/bidder assumes the risk of recovering these costs if they exist. In the bidding system as proposed by the decision and the 205 filing, the generator/bidder could bid the marginal cost of generation plus no-load and start-up and be assured that, if dispatched, it would recover all these costs. So far as breaking even is concerned, it would make all generators, though they may be slow-starting, equivalent to a unit that has only one operating level and starts instantly without cost. Bidders are not required to bid no-load and start-up. The advantage of bidding them is a better assurance of not losing any money. The disadvantage is that bidding them may move the unit further up in the dispatch order, so that it could run fewer hours or not at all.

The implications of all generators bidding their short-run operating costs are explained and illustrated in **Attachment B**.[4] Some generator's cost always sets the MCP, so each generator dispatched takes in revenue applicable to its fixed costs only to the extent that its operating costs are lower than those of the plant on the margin. If the entire system consists only of generating plants whose existence is justifiable based on capital costs, running costs, and hours run, all units will fail to recover at least some portion of their fixed costs so long as variable cost bids set MCP. [5]

THE ADVANTAGE OF EFFICIENCY

In the **Attachment B** system where all generators bid variable costs and all end up losing money, the system is deliberately constructed with the perfect mix of the available generation resource types. Any differences in efficiency among generators are exactly compensated by corresponding differences in fixed costs. For example, another efficient baseload unit could not be added without increasing system costs, because this unit could not run enough hours. The real world is not so neat. Newer generating units could be added that would be significantly more efficient than most or all of the generation in the existing resource base, and the efficiency difference would not necessarily be fully counterbalanced by higher capital cost. Conceivably, a new generation unit could be added that could pay for itself based on the difference between its low operating cost and the higher operating costs of the existing resource base that would ordinarily set MCP.

The efficiency of fuel-burning generators is normally measured in terms of heat rates expressed in Btu/kWh. A low heat rate indicates less fuel burned per unit of electricity generated, and therefore high efficiency. **Table 1** shows "incremental energy rates" that describe the marginal efficiency of Southern California Edison Co.'s system in Btu/kWh during parts of the year, and for the whole year. Most of this time, natural gas-fired generation is the marginal resource, in which case the values shown are heat rates. During other times, resources other than gas are on the margin, in which case the IERs are equivalent heat rates based on cost. Average for the year is 9,137 Btu/kWh. This is for 1994, but SCE's resources have not changed much since then.

TABLE 1
SCE INCREMENTAL ENERGY RATES, 1994

(Btu/kWH)

	Summer			Winter			All Year
	On	Mid	Off	Mid	Off	Super-Off	All Hours
IER	12977	9292	7730	11244	8533	7069	9137
Hours	510	765	1653	2179	219	1458	8760

A new generating unit that employs the most efficient technology currently available would have a heat rate of around 7,200 Btu/kWh. **Table 2** shows that such a resource operating 100 percent of the year in a Southern California environment where gas costs $2.33/MMBtu would earn $39.54/kW as return to fixed cost and profit for the year. As later tables will illustrate, this is not enough money to keep the new resource viable. The situation would improve if gas costs were to increase, because burning less gas per kWh generated would save more money. However, $2.33/MMBtu is already well above the actual cost of gas for electric utility generation in 1996. Until fuel prices rise, energy efficiency advantages will remain significant, but not sufficient in themselves to provide the incentives new generators need to enter the market. To the extent that efficiency advantages exist, they will erode as less efficient units are retired and more efficient units enter.

TABLE 2
ANNUAL NET REVENUES FROM HEAT RATE DIFFERENTIAL
(per kilowatt of delivered capacity)

Market Heat Rate, Btu/kWh	9137
Fuel Price, $/MMBtu	2.33

Project Heat Rate	Project Capacity Factor 20.%	40.%	60.%	80.%	100.%
5000	16.89	33.78	50.66	67.55	84.44
5200	16.07	32.14	48.21	64.29	80.36
5400	15.26	30.51	45.77	61.02	76.28
5600	14.44	28.88	43.32	57.75	72.19
5800	13.62	27.24	40.87	54.49	68.11
6000	12.81	25.61	38.42	51.22	64.03
6200	11.99	23.98	35.97	47.96	59.95
6400	11.17	22.35	33.52	44.69	55.86
6600	10.36	20.71	31.07	41.43	51.78
6800	9.54	19.08	28.62	38.16	47.70
7000	8.72	17.45	26.17	34.89	43.62
7200	7.91	15.81	23.72	31.63	39.54
7400	7.09	14.18	21.27	28.36	35.45
7600	6.27	12.55	18.82	25.10	31.37
7800	5.46	10.92	16.37	21.83	27.29
8000	4.64	9.28	13.92	18.57	23.21
8200	3.82	7.65	11.47	15.30	19.12
8400	3.01	6.02	9.03	12.03	15.04
8600	2.19	4.38	6.58	8.77	10.96
8800	1.38	2.75	4.13	5.50	6.88
9000	0.56	1.12	1.68	2.24	2.80

DEMAND BIDDING

Attachment B and the above section on "The Power Exchange and Direct Access" describe how demand bids would be used in the Power Exchange and could sometimes set MCP. Demand bids would set MCP when demand for energy at the price bid by the last generator dispatched exceeds system energy output. Demanders would then, in effect, be bidding against each other for a limited amount of energy, and prices could go much higher than any generator's marginal cost.

The demand bids in **Attachment B** differ slightly from demand bids as described in the 205 filing. In **Attachment B** the price element of a demand bid is the lowest price a demander is not willing to pay; i.e., the price at which at which the demand drops. In the 205 filing, the price element is the highest price the demander is willing to pay. The difference between the two is that the **Attachment B** bid should be higher by whatever is the minimum increment of price. All other things being equal, however, the method of the 205 filing results in higher prices when demand bids clear the market, because MCP is set by the lowest bid of a demander still receiving energy, not the still lower highest bid of a demander not receiving energy.

LAST BLOCK PREMIUM

As illustrated in **Attachment A**, a generator can receive a contribution to fixed costs even when paid according to its own variable cost bid, if that bid represents the cost of reaching a level of output higher than the generator's point of optimal efficiency. For example, ***ER 94*** lists return to service for Silver Gate Units 3 and 4 as a capacity expansion option for San Diego Gas and Electric.[6] Those units are considered to have six incremental blocks. Heat rates and output for the fifth and sixth blocks, respectively, are 102 MW at 12,021 Btu/kWh and 128 MW at 12,106 Btu/kWh. Assuming a gas price of $2.10/MMBtu, average variable cost for the fifth block is $25.24/MWh [(12,021/1,000,000)* $2.01 *1,000]. Average variable cost for the sixth block is $25.42/MWh, and marginal cost for the sixth block is $26.12/MWh {[(128 * 25.42) - (102 * 25.24)]/24}. Thus the plants can earn $.70/MWh ($26.12 - $25.42) toward fixed costs with a marginal cost bid of 128 MW at $26.12/MWh. A small efficiency penalty is necessary to realize this gain.

The principle illustrated with Silver Gate 3 and 4 does not apply to all plants and seldom makes a large difference in price. Thus it probably does not represent a significant opportunity for generators to make money.

GAMESMANSHIP

To this point, we have assumed that supply bidders into the PX would bid their running costs, or marginal costs. What if they did not? If bidding behavior is responsible for getting PX prices high enough, then the success of restructuring will be decidedly mixed. The Decision is clear about the CPUC's intent to keep the restructured market free of the influence of market power. "The mere existence of market power can undermine our goals for electric restructuring and should be avoided," the Decision says (at p. 91). This subject will be explored in our forthcoming testimony on market power.

ANCILLARY SERVICES

The discussion thus far has been limited to returns from the sale of real power through the PX. Under the proposed restructuring, this would not be the only way generators could earn money. They could also sell ancillary services. The "203 filing" for the Independent System Operator (ISO) identifies the necessary ancillary services as follows:

1. Spinning Reserves
2. Non-Spinning Reserves
3. Replacement Reserves
4. Black Start
5. Load Following
6. Energy Imbalance
7. Reactive Power/Voltage Control
8. Loss Compensation

The 203 filing says the ISO will procure these services in the marketplace. The reserve services, numbered 1, 2, and 3, would be provided by generators not dispatched to meet load or by unloaded capacity of dispatched generators. Spinning and non-spinning reserves together would total about seven percent of total system load at any time, per reliability guidelines of the Western States Coordinating Council. Generators selected to provide spinning reserve would be paid the difference between their incremental energy bids and the MCP, making them indifferent between running to actually produce and sell energy and running with some capacity left unloaded, so as to maintain spinning reserve. Non-spinning reserve would be called upon less often, and replacement reserve still less often, so they would probably be paid less than spinning reserve. The remaining five ancillary services, those not designated as "reserve," offer revenue opportunities for particular generators or at particular times.

Black start and reactive power are ancillary service that depend on location. Few competitors are likely to be positioned to provide the services where they are needed. Therefore, well positioned generators could have negotiating leverage to obtain favorable prices. Excessive exploitation of this leverage would invite entry of competitors and raise market power concerns.

Estimates of the total value of the ancillary services market, in proportion to generators' total sales, tend to hover from three to ten percent, but no adequate estimate is yet available. If the higher end of this range is more correct, or if a potential for revenue from ancillary services in excess of this range exists, any concerns about the PX not providing sufficient returns to generators are accordingly diminished.

SUPPLY AND DEMAND

As explained above and in **Attachment B**, generators' best opportunities for fixed cost recovery and profit will probably occur when consumer demand exceeds available generation capacity. Under the proposed PX bidding procedures, this situation would allow MCP to be set by a demander's bid or energy value, which could be considerably higher than the variable cost of any generator. Generating units that run few hours and have relatively high variable costs, such as peaking units, may have to depend heavily on prices set by the demand side. Thus the question of whether and when new generators can receive returns sufficient to turn a profit from the market depends (not surprisingly) on supply and demand.

At the outset of the restructured market, available capacity includes a comfortable reserve margin intended to assure reliability. With restructuring, the investor-owned utilities would no longer be required to plan for any generation capacity, much less a reserve. Responsibility for day-to-day reliability would shift to the Independent System Operator (ISO), and market forces would be relied on to match supply with demand over the long term. By effectively eliminating the requirement for a long-term reserve margin, restructuring will tend set back the date when new capacity is needed by the investor-owned utilities. However, by also eliminating the obligation of investor-owned utilities to run their plants to meet peak demand, restructuring could advance that date, because the utilities may shut down plants sooner.

Besides the elimination of reserve requirements and obligation to generate, other important factors affecting PX prices include the elasticities of demand and supply. If capacity during peak hours becomes relatively scarce but demand is highly elastic, the capacity shortage will have only a small effect on price. Generators will not receive high margins over their costs, and new market entrants will not receive a strong signal to invest. Inelasticity of demand would have the opposite effect, sending prices high and attracting new entrants.

Supply elasticity may have its effects both off-peak and on-peak. Prices off-peak could be low enough that some generators do not try to compete for off-peak sales. This would mean less capacity in the market and a possibility that demand-side bids could set MCP at times other than system peak. This would raise average PX prices and perhaps attract new generators capable of producing at higher capacity factors. High prices on-peak could attract competition from out of state suppliers and energy resellers that hold bilateral contracts, tending to moderate prices and discourage entry of new peaking units for the California market.

QUANTIFYING THE PROBLEM

A quantification of the new entrants issue, although difficult, may be helpful. How high do PX prices need to be to attract and maintain new generators? They need to be high enough to fully cover operating costs, pay fixed costs, and recover invested capital with whatever return financial markets demand. A generator's earnings will depend on how many hours it can get dispatched and the prices it receives during those hours. Generators such as combined cycles or coal plants, whose high efficiencies or low fuel prices allow them to bid low prices, get dispatched more hours, but they generally will have more fixed costs to cover than generators such as combustion turbines that have higher operating costs.

A generator's total revenue from the PX can be estimated as the number of hours it is dispatched times the average PX MCP for those hours. Some of this revenue will be needed to cover fuel and other variable costs. The remainder can go toward fixed costs and profit. **Table 3** shows how much money a generator can clear, per kW, for various combinations of hours dispatched and average margin received over running costs during those hours. For example, if a certain generator could operate for $20/MWh and get itself dispatched by the PX for 42 percent of the year (3,679 hours), it would make $91.98 per kW for the year if it could receive an average MCP of $45/MWh ($20/MWh operating cost plus $25/MWh average margin).

TABLE 3
Fixed Cost Recovery and Profit in $/kW-yr
As determined by average operating margin and running hours

**	Average margin received over running cost, $/MWh							
	10	**15**	**20**	**25**	**30**	**35**	**40**	**300**
2%	1.75	2.63	3.50	4.38	5.26	6.13	7.01	52.56
7%	6.13	9.20	12.26	15.33	18.40	21.46	24.53	183.96
12%	10.51	15.77	21.02	26.28	31.54	36.79	42.05	315.36
17%	14.89	22.34	29.78	37.23	44.68	52.12	59.57	446.76
22%	19.27	28.91	38.54	48.18	57.82	67.45	77.09	578.16
27%	23.65	35.48	47.30	59.13	70.96	82.78	94.61	709.56
32%	28.03	42.05	56.06	70.08	84.10	98.11	112.13	840.96
37%	32.41	48.62	64.82	81.03	97.24	113.44	129.65	972.36
42%	36.79	55.19	73.58	91.98	110.38	128.77	147.17	1103.76
47%	41.17	61.76	82.34	102.93	123.52	144.10	164.69	1235.16
52%	45.55	68.33	91.10	113.88	136.66	159.43	182.21	1366.56
57%	49.93	74.90	99.86	124.83	149.80	174.76	199.73	1497.96
62%	54.31	81.47	108.62	135.78	162.94	190.09	217.25	1629.36
67%	58.69	88.04	117.38	146.73	176.08	205.42	234.77	1760.76
72%	63.07	94.61	126.14	157.68	189.22	220.75	252.29	1892.16
77%	67.45	101.18	134.90	168.63	202.36	236.08	269.81	2023.56
82%	71.83	107.75	143.66	179.58	215.50	251.41	287.33	2154.96
87%	76.21	114.32	152.42	190.53	228.64	266.74	304.85	2286.36
92%	80.59	120.89	161.18	201.48	241.78	282.07	322.37	2417.76
97%	84.97	127.46	169.94	212.43	254.92	297.40	339.89	2549.16

****:** Fraction of the Year During Which Unit Operates

If supply bidders into the PX bid their marginal costs and supply bids always set MCP, PX prices should be similar to what are now termed the system marginal costs of the utilities. [7] Production cost model output for Southern California Edison shows system marginal costs through a full year ranging from $12/MWh to $44/MWh, with an average of about $24/MWh (year 1994 resources, with natural gas prices averaging $2.33/MMBtu). When the hour by hour marginal costs are placed in order, highest to lowest, running averages and corresponding percentages of the year turn out as shown on **Table 4** (including estimated variable operation and maintenance costs, but not including no-load and start-up).

TABLE 4
Edison's Average Marginal Costs

System Average MC in $/MWh	43	32	28	26	25	24
Percent of year Included in Avg.	10	20	40	60	80	100

If these marginal costs can be taken as proxies for PX energy prices (excluding no load and start-up), a generator that managed to be dispatched at all times, or 100 percent of the year, would receive an average price of $24/MWh; while a generator dispatched only during the highest-priced 10 percent of the hours would receive an average price of $43/MWh.

These prices would not likely attract many new generators into the market. Existing generators also would have difficulty meeting their revenue requirements without help from a Competition Transition Charge (CTC). Some of the most efficient fossil-fired generation equipment now available, combined cycle units, would have operating costs of around $17/MWh (7,200 Btu/kWh, $2.33/MMBtu). Assuming, for both conservatism and convenience, that such a plant could negotiate a highly favorable gas supply contract, so as to run for $14/MWh, it might be dispatched 97 percent of the year. **Table 3** shows how much it would earn toward fixed cost recovery and profit: $84.97/kW. This optimistic figure is not high enough to make a new plant viable. A new combined cycle plant in southern California would probably have to clear at least $100/kW per year if the estimates in the Energy Commission's ***ER 94*** can be relied on (**Table 5**). A new simple-cycle combustion turbine could get by on less, but would run fewer hours and have higher operating costs.

TABLE 5
Computation of Annual Fixed Cost
SCE Option 9, CC, New Site In-Basin

		Year	% Of Instant	Instant By Year	Esc Cost	Future Cost
Instant Cost, $/kW	783					
Transmission, $/kW	9	1	1	7.92	7.47	10.65
Total Capital, $/kW	792	2	2	15.84	15.53	20.47
Year of Estimate	1991	3	22	174.24	177.69	216.39
Inflation Rate, %	4	4	55	435.60	462.00	519.97
Real Const. Esc. Rate, %	0	5	20	158.40	174.72	181.74
Nominal Const. Esc. Rate, %	4	6	0	0.00	0.00	0.00
Interest During Const., %	8	7	0	0.00	0.00	0.00
Const. Period, Yrs.	5	8	0	0.00	0.00	0.00
On-Line Year	1994		**100**	**$792.00**	**$837.40**	**$949.21**

Fixed O&M Cost, $/kW-yr		9.20
Year of Estimate		1991
Wtd. Avg. Cost of Cptl., %		9.70
Book Life, Yrs.		29.00
Esc. Fixed O&M, $/kW-yr		10.30
PV of Fixed O&M		142.92
Total to be financed	1,092.00	
Annual Payment., $/kW		113.69

Source: Data from ***ER 94***, Utility Supply Option Characterizations for Large Utilities, p. SCE-4.

As the restructured market matures, system marginal costs of generation may not rise (except due to fuel prices increases that would raise both PX prices and operating costs), but consumer demand for electricity will continue to grow. Some generation units may be retired. Fixed operation and maintenance costs, even for a unit that is completely paid for, can easily exceed $7/kW-yr.[8] Certain older utility gas-fired units currently run 2 percent of the year or less, and **Table 3** shows that such a unit would have to receive PX prices equal to its own operating cost plus about $40/MWh to clear $7/kW-yr. **Table 6** identifies 1,965 MW of capacity belonging to Southern California Edison Company that, according to the Energy Commission's production cost model, will run 2 percent of the year or less in 1998.

TABLE 6
Edison Units That Run 2% Of The Year Or Less in 1988

Plant	MW	Capacity Factor
Alamitos #1	175	1.58%
El Segundo #2	175	1.45%
Highgrove #1	33	1.75%
Highgrove #2	33	1.73%
Highgrove #3	44.5	1.40%
Highgrove #4	44.5	1.77%
Redondo Beach #5	175	1.94%
Redondo Beach #6	175	0.96%
Long Beach CC	530	0.04%
Alamitos #7 (CT)	133	0.21%
Etiwanda #5 (CT)	126	0.16%
Huntington #5 (CT)	133	0.13%
Mandalay #3 (CT)	140	0.28%
Elwood #1(CT)	48	0.60%
Total Megawatts	**1,965**	

Source: ELFIN production cost model runs performed by Donna Stone, Electricity Resource Assessment Office, 1996.

After just a few years, the combination of demand growth and closure of older generation may create a seller's market for energy during peak demand hours and perhaps at other times. In this circumstance, the 205 filing for authorization of the PX provides that MCP will be set either at what demanders are willing to pay for energy, or should sufficient information about what they are willing to pay be lacking, at "an administratively pre-determined cap". The filing does not give any clues as to how high the cap might be, but preliminary drafts suggested that it could be $1/kWh or $2/kWh. **Table 7** shows how a cap price of $1/kWh ($1,000/MWh), if in effect for 1 percent of the hours (87.6 hours per year), would affect the system average marginal costs shown on **Table 4**.

These marginal costs, if translated into PX prices, would obviously be much more attractive to new generators. They would support new combined cycles, new peakers, and perhaps renewable resources such as wind and solar.

TABLE 7
Modified Average Marginal Costs

System average MC in $/MWh	139	80	52	42	37	34
Percent of year Included in Average	10	20	40	60	80	100

HIGHER PRICES WHEN?

Like the future price of any other commodity, the future price of electricity on California's PX cannot be estimated with much certainty. When the PX begins operation in 1998, prices like those of **Table 4** would result if the utilities continue with business as usual, except for the formality of bidding their resources into the PX and buying them back out again. Revenues from selling into the PX would not fully cover utility costs of generation, but some the shortfall would be covered by the CTC. CTC can be collected to cover a unit's revenue requirements whether it runs or not, so some inefficient units may or may not run. By 2003, the utilities will have collected all the CTC to which they are entitled.

Also around 2003, the supply system (utilities and direct access providers) is expected to need new capacity to meet the demands of its distribution customers.[9] In other words, expected demand for electricity edges ahead of expected supply in about 2003 or soon thereafter. Therefore, PX prices in 2004 may look more like **Table 7** than **Table 4**, and new generators will have the incentives they need to enter the California market. Most will probably need contracts to guarantee sale of at least part of their output at a known price. Some, especially those financed mainly with equity, may find sales into the PX more profitable than firm contracts.

ISSUES AND ANSWERS

To more fully articulate and summarize the arguments of this paper, the following issues are put forward, along with Staff positions relative to these issues.

1. Will bidders into the PX bid the costs they actually expect to incur in running their plants (variable costs for a single-block plant or marginal costs for a multi-block plant)?

   Position: Yes, they will tend to do so, provided the market is reasonably free of market power and opportunities for gaming. Higher bids would cause a plant to be dispatched fewer hours, reducing revenue that could contribute to fixed costs recovery and profit. Bidders in aggregate would be better off if they all bid higher, but any individual bidder's interest is best served by bidding as low as it can without offering to run at a loss.

2. Will no-load and start-up bids be effective to significantly enhance generators' fixed cost recovery and profit?

   Position: Generally not. These bids are only intended to provide full recovery of operating costs over 24-hour periods when PX prices do not bring full recovery. They allow bidders to more fully describe their avoidable costs while also providing a way to assure that sequential blocks of generation will be taken in order. Bidding high values for no-load and start-up would cause a generator to be dispatched less often, and for fewer hours, such that its revenue would be lessened. In this respect, no-load and start-up bids are no different from energy bids.

3. Will sale of ancillary services provide generators with a large share of their income streams?

   Position: Generally not, at least not in comparison to the income streams from sales of real power. The market's need for ancillary services is small in comparison to real power. Ancillary service markets are proposed for three kinds of reserve: spinning, non-spinning, and replacement. Spinning reserve will be three and a half percent of load and it will be paid so as to be made indifferent between providing spinning reserve and providing real power. The other two categories of reserve will be less frequently called upon and probably paid less. Of the ancillary services other than reserves, voltage support/reactive power probably constitutes the largest market, and this market is highly location-specific. Regulators will not allow a strategically located generator to exploit its position without limit.

4. Will new generators that sell their output by way of bilateral contracts be able to receive more revenue than if they sold into the PX and took the MCP?

   Position: Probably not. All energy buyers that might enter into bilateral contracts would also have the option of buying from the PX. They might prefer stability of a contract price, but most generators would prefer stability to an even greater degree than buyers. Generators would value stability more because power sales constitute the majority of their business, if not all of it. They would also have substantial fixed cost obligations associated with their investment in capacity. Therefore, to obtain an assurance of stable income, a generator would have to accept contract prices that have a lesser present worth over the contract life than the parties' expectation of PX prices.

Alternative View: If consumer are risk adverse, they might prefer a firm contract with a single generator. Power providers with strong equity positions might be able to self-finance these projects.

5. Will the excess of PX price over generators' operating costs when demand-side bids (or the price cap that serves in their place) clear the PX market be a significant source of revenue for generators, particularly where fixed cost recovery and profit are concerned?

Position: Yes. If the idea that generators will bid their avoidable operating costs is accepted, this answer follows naturally, because without it many (perhaps all) generators would fail to recover fixed costs and ultimately go out of business. Some generators can make money on the difference between their low operating costs and the higher operating costs that may sometimes set MCP. Differences between operating costs, however, are usually fairly small in comparison to revenue requirements for fixed cost and profit.

ECONOMIC EFFICIENCY

The restructuring now under way aims to improve the economic efficiency of the electric supply system by making the generation of electricity a competitive business. It will succeed if: 1) it encourages the survival and prosperity of the more efficient generators, and 2) it gives correct signals as to when and where new generators should enter the market.

The dispatch and payment procedures proposed for the Power Exchange should effectively encourage the more efficient generation plants and technologies, because they can operate more cheaply, bid lower, and get dispatched more often. When they are dispatched, they will receive higher margins over operating costs than less efficient units.

Demand bidding should make the restructured system more efficient in that consumers can decide how much capacity they are willing to pay for. If demanders bid high prices, a larger amount of capacity can be supported, and few consumers will have to cut their energy consumption significantly during system peaks. If they bid lower prices, less capacity will be available, and greater demand curtailments will be necessary. Every curtailment will be voluntary, however. In the same way that many consumers choose not to buy strawberries when they are expensive, some consumers may choose not to buy as much electricity when it is expensive. Generators will respond to consumer preferences by supplying just the amount of capacity that consumers are willing to pay for, and no more. Perhaps the reserve margins historically sustained in the regulated electric utility industry have reflected exactly the amount of capacity consumers are willing to pay for, but not likely. In the restructured market, reserve margins will probably be lower, saving costs and improving efficiency. [10]

SYSTEM RELIABILITY

Restructuring will not change the reliability requirements for the interconnected system of the Western States Coordinating Council. The Independent System Operator will be required to observe all the same procedures that insure day to day and hour to hour reliability in the interconnected system now. From a longer term perspective, however, the concept of reliability will take on a new meaning. In the present system, electricity is expected to be available in whatever quantity consumers demand at the pre-ordained and approved rates. In the restructured system, electricity will, in effect, be rationed during periods of high demand according to what different consumers are willing or able to pay. No doubt regulators will make sure that lifeline rates provide a degree of protection to those least able to pay, but the system will not work if everyone is fully protected. An element of scarcity is fundamental to the restructured system requires an element of scarcity; otherwise prices would not rise high enough. This means that some demand will be priced out of the market at certain times. If restructuring did not occur, and this demand were always met, it would met by providing consumers with a degree of reliability they would not be willing to pay for if they had a choice. Thus, in a way, the restructured system will be less reliable, but only for those to whom reliability is not worth what it costs.

Before embracing restructuring too eagerly, however, everyone should recognize that theory, such as this paper propounds, works best in idealized models and may not work nearly so well in the real world. For example, about 15 percent of California's generating capacity is hydroelectric. Its energy production depends on unpredictable and widely varying weather cycles. Perhaps the market for electricity in California is such that consumers would be willing to pay for non-hydro generating capacity that would only be called upon to generate one year in ten, but perhaps no one is willing to finance a generating plant that would receive revenue only one year in ten. In this case, a market failure arguably would impair reliability for consumers willing and able to pay for it.

Another problem could arise from the supply curve being overly flat for much of the year. If generators must depend on the higher cost or lesser efficiency of other generators to set PX prices, a flat supply curve implies that operating margins of many generators will be small. Small margins do not provide a strong motivation to stay in operation. Some generators might choose to forgo the small contribution to fixed costs that they could earn by operating. This could make the supply of electricity during a substantial portion of the year highly variable. Should electricity become scarce, demand bidding could raise the PX price, bringing more generators on line, but this could cause a pulsating price cycle as a scarcity and abundance alternate. Perhaps there would be no harm done; prices would pulsate, and those who find the situation uncomfortable could smooth their revenue or payment streams by signing contracts. The system might be less able to respond to conditions of unexpected high demand, however, and the price swings in the PX could make financing more expensive.

Other market failures, perceived only hazily at this point or not yet perceived at all, are possible under restructuring. Big changes entail big risks. Industry leaders and regulators should be prepared to respond.

CONCLUSION

The restructuring as proposed by the CPUC includes a mechanism, in the form of the Power Exchange, that can provide the necessary incentives for new generation to enter the market. The same incentives may be reflected indirectly in bilateral contracts. Conceivably, new generation could enter because it is so much more efficient than existing generation that the difference between its operating costs and the higher costs that would generally set MCP will completely cover the new generation's revenue requirements for fixed cost and profit. This, however, is unlikely. Although efficiency improvements have been dramatic in recent years, and further gains may be expected, they are not enough to create sufficient operating margins unless fuel prices rise dramatically. More likely, energy prices will rise high enough to encourage new market entrants when the demand for electricity starts to exceed the available supply during peak periods. This will cause demand bids to set MCPs in the Power Exchange at levels well above the operating costs of any generator. These high prices, combined with efficiency advantages, and possibly with ancillary service revenues, should allow significant amounts of new generation to enter the California market by about year 2003. Therefore, the same or similar forces will continue to bring new generation into the market as needed.

END NOTES

Witness Qualifications
for
ROBERT D. GROW

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1. California Energy Commission, ***1994 "Electricity Report"***, Energy Forecasting and Resource Assessments Division, November 1995, p. 1.

2. Order Instituting Rulemaking on the Commission's Proposed Policies Governing Restructuring California's Electric Services Industry and Reforming Regulation, Decision 95-12-063, R. 94-04-032, Dec. 20, 1995.

3. **Appendix A** is an unpublished article by Robert D. Grow of the California Energy Commission Staff.

4. **Appendix B** is a reprint from Public Utilities Fortnightly of an article by Robert D. Grow of the California Energy Commission Staff. Corrections are by the author.

5. Results similar to those of **Attachment B** were obtained by Manuel Ramirez of ERAO using the UPLAN-E model developed by LCG Consulting of Mountain View, CA.

6. ***ER 94***, **Appendix A**, Section E, p. SDG&E-4.

7. System marginal costs are the incremental cost and most expensive generation dispatched to meet load. In a PX, they would be the most expensive successful bidder.

8. Based on "Return to Service" fixed O&M estimates in ***ER 94*** for Etiwanda and Silver Gate, plus MAPS data set for Western States Coordinating Council.

9. ***ER 94***, p. 116: "PG&E, Edison and LADWP have adequate physical capacity through at least 2003, assuming the BRPU resources are added." The BRPU resources referred to are 246 MW for PG&E, 684 MW Edison, and 502 MW for SDG&E. The BRPU results have been challenged, and it can no longer be assumed that the BRPU resources will be added.

10. Other ***ER 96*** testimony (Susan Bakker's) points out the inefficiencies inherent in the way MCPs and payments to constrained-on generators are determined under the procedures outlined in the WEPEX filings.